REVIEW MEMORANDUM
DRAFT 7 DE Admin. Code 1130 (TITLE V) OPERATING PERMIT

Delaware City Refining Company
4550 Wrangle Hill Road
Delaware City, Delaware 19706
Permit No.: AQM-003/00016 – Part 1 (Renewal 2)
AQM-003/00016 – Part 2 (Renewal 1)
AQM-003/00016 – Part 3 (Renewal 2)

BACKGROUND

The Delaware City Refinery (DCR), NAICS Code 32411, is located on a 5,000 acre tract in Delaware City and between US Route 13 and Delaware Route 9. The DCR has the potential to emit greater than 25 tons per year of nitrogen oxides (NO_X) and volatile organic compounds (VOCs), greater than 100 tons per year of carbon monoxide (CO) and sulfur dioxide (SO_2), and greater than 25 tons per year of hazardous air pollutants (HAPs) as listed in Section 112(b) of the Clean Air Act Amendments of 1990. Therefore, the DCR is subject to the requirements of 7 **DE Admin. Code 1130**.

The DCR was owned by Star Enterprises at the time the initial Title V application was submitted to the Department. On July 1, 1998, Shell Oil Products (Shell), Saudi Refining, Inc., and Texaco Inc. formed Motiva, combining the major elements of Shell's and Star's eastern and southern refining and marketing businesses. The ownership of Star Enterprise was transferred to Motiva L.L.C. on October 1998. In October 2001, Texaco Inc. divested itself of its share in the Company. Motiva sold the DCR to The Premcor Refining Group, Inc. on May 1, 2004. On September 1, 2005, Premcor, in turn, was acquired as a wholly owned subsidiary by The Valero Energy Corporation (Valero). The Delaware City Refining Company (DCRC), a subsidiary of PBF Energy acquired the DCR from Valero on May 31, 2010.

DCRC's Title V fees are paid in full.

DCRC has not requested that any information be considered confidential.

CORRESPONDENCE CHRONOLOGY

Correspondence/Date	Subject
Permit renewal application submittal from DCRC dated May 22, 2012	Application for permit renewal.
Application completeness determination letter from Paul Foster dated June 26, 2012	Application was judged incomplete due to the compliance certification.
Additional Information from Premcor dated July 30, 2012	Requested compliance certification was submitted.
Letter to Premcor from Paul Foster dated September 19, 2012	Application was judged administratively complete
Additional Information from Premcor dated December 5, 2012	Request to incorporate additional Regulation 1102 permits in the Title V permit renewal.

EMISSION POINT AND EMISSION UNIT IDENTIFICATION

In accordance with 7 **DE Admin. Code** 1130.7.3.1, an "*application for permit renewal may address only those portions of the permit that the Department determines require revision, supplementing, or deletion*." The following refinery units and operations need revision and supplementing in this Title V renewal:

- Crude Unit
- Combined Cycle Units
- Tanks 47, 166, 205 and 261
- Fluid Catalytic Cracking Unit
- Fluid Coker Unit
- Waste Water Treatment Plant Vapor Combustion Unit
- Petroleum Coke Storage and Handling Complex
- Tanks 47, 166, 205 and 261
- Cracked Naphtha Hydrotreater Unit
- CNHT Heaters 25-H-401 & 25-H-402

Permit Condition 1.a – *Emission Unit Information* fully details these emission units and emission points.

INSIGNIFICANT ACTIVITIES

Insignificant activities are included in Part 2 Condition 3 – Table 1.ob.7.

REGULATION NO. 1102 PERMITS

The following permits have been issued to the Refinery since the last permit revision in April 2011:

- **Permit: APC-82/1209-OPERATION (Amendment 7)** was issued on June 14, 2012 for the new Petroleum Coke Storage and Handling Complex. It supersedes **Permit: APC-82/1209-OPERATION (Amendment 6)**. New emission and operational limitations and testing, monitoring and record keeping requirements have been incorporated into Part 2's Condition 3 – Table 1.db. See Table 1 for detailed changes to the Title V permit.

- **Permit: APC-98/0522-OPERATION (Amendment 1)(NSPS)** was issued on August 15, 2012 for the Cracked Naphtha Hydrotreater's Heater 25-H410 and Reboiler Heater 25-H-402. It supersedes **Permit: APC-98/0522-OPERATION (RACT)(NSPS)**. New emission and operational limitations and testing, monitoring and record keeping requirements have been incorporated into Part 2's Condition 3 – Table 1.ga. See Table 2 for detailed changes.

- **Permit: APC-98/0523-OPERATION (Amendment 1)(NSPS)** was issued on August 15, 2012 for the Cracked Naphtha Hydrotreater Unit. It supersedes **Permit: APC-98/0523-OPERATION (RACT)(NSPS)(NESHAP)**. New emission and operational limitations and testing, monitoring and record keeping requirements have been incorporated into Part 2's Condition 3 – Table 1.ga and gb. See Table 3 for detailed changes.

- **Permit: APC-94/0710-CONSTRUCTION/OPERATION (Amendment 1)(NESHAP)(NOx RACT)** was issued on October 22, 2012 for the Waste Water

Treatment Plant Vapor Combustion Unit's fuel switch project. It supersedes **Permit: APC-94/0710-OPERATION (NESHAP)(Nox RACT)**. New emission and operational Limitations for VOC, CO and SO_2 and have been incorporated into Part 2's Condition 3 – Table 1.ac. See Table 4 for detailed changes.

- **Permit: APC-81/0829-OPERATION (Amendment 8)(PSD-NSR)** was issued on September 7, 2011 for the Fluid Coker Unit, FCU carbon monoxide boiler, wet gas scrubber and selective Non-catalytic reduction system. It supersedes **Permit: APC-81/0829-OPERATION (Amendment 7)**. New Emission and Operational Limitations and testing, monitoring and record keeping requirements have been incorporated into Part 2's Condition 3 – Table 1.da. See Table 5 for detailed changes.

- **Permit: APC-82/0981-OPERATION (Amendment 9)(NSPS)** was issued on April 30, 2012 for the Fluid Catalytic Cracking Unit, FCCU carbon monoxide boiler and wet gas scrubber system. It supersedes **Permit: APC-82/0981-C/O (Amendment 8)(NSPS)**. New Emission and Operational Limitations and testing, monitoring and record keeping requirements have been incorporated into Part 2's Condition 3 – Table 1.e. The permit's attachment "*CO Boiler Bypass Events – Conversion to Full Burn*" has been added to the Title V permit in Attachment G. See Table 6 for detailed changes.

- **Permit: APC-97/0503-OPERATION (Amendment 8)(NSPS)** was issued on July 3, 2012 for the Combined Cycle Units modification project. It supersedes **Permit: APC-97/0503-OPERATION (Amendment 7)(NSPS)**. New emission and operational limitations for PM10, TSP, CO, VOCs, SO_2, H_2SO_4 and lead were added along with testing, monitoring and record keeping requirements. The new requirements have been incorporated into Part 3's Condition 3 – Table 1.d. See Table 7 for detailed changes.

- **Permits: APC-80/0868-OPERATION (Amendment 3)(MACT)(VOC RACT)(NSPS)** and **APC-80/0869-OPERATION (Amendment 6)(MACT)(VOC RACT)(NSPS)** was issued on June 22, 2012 for Tanks 47, 166, 205 and 261 and associated piping modifications. No previously issued permit was superseded. Tanks 166, 205 and 261 are subject to new applicable requirements and their position in the permit has changed from Part 1, Condition 3 – Table 1.fc to Table 1.fb. Tank 47 remains in Table 1.ff and Table 1.fg. There is a new emission limitation for all four tanks located in Table 1.fb.1.iii. See Table 8 for detailed changes.

- **Permit: APC-81/0828-OPERATION (Amendment 2)(PSD-NSR)** was issued on September 7, 2011 for the Crude Unit. It superseded **Permit: APC-81/0828-OPERATION (Amendment 1)**. New requirements for controlling VOCs during process unit turnarounds were incorporated into Part 2's Condition 3 – Table 1.c. See Table 9 for detailed changes.

Table 1

Permit: APC-82/1209-OPERATION (A7) New Petroleum Coke Storage and Handling Complex			
Condition No.	**Condition Description**	**Transferred to**	**Changes to Related Compliance Demonstration**
2.1.1	PM emissions from the [identified] baghouses shall not exceed 0.014 grains/scf.	Part 2, Table 1.db.1.i.C	Yes
2.1.1	PM emissions from the Pugmills and Scrubber (Emission Pt. PS-06) shall not exceed 0.067 grains/scf.	Part 2, Table 1.db.1.i.D	Yes
2.1.2	Aggregate emissions from the emission points identified in sections B and C above, truck and railcar loading and from the storage pile in the barn shall not exceed 27.2 tons per year of PM and 20.1 tons per year of PM_{10}. "Tons per year" shall mean total emissions on a rolling 12-month basis.	Part 2, Table 1.db.1.i E	Yes
2.4	The Company shall not cause or allow visible particulate emissions of any petroleum coke that is being transported by a motor vehicle within the refinery.	Part 2, Table 1.db.1.i F	Yes
2.5	The Company shall not cause or allow the transport of material to or from the barn in such a manner as may cause a condition of air pollution.	Part 2, Table 1.db.1.i.G	Yes
3.3	The Company shall pave and maintain as paved all roads and truck movement areas within the facility that are used in transporting or moving petroleum coke.	Part 2, Table 1.db.1.ii.H	Yes
3.4	The Company shall regularly use a street sweeper or other approved method to clean the paved areas where coke accumulates.	Part 2, Table 1.db.1.ii.I	Yes
3.5	Trucks containing coke must be covered at all times except when being loaded with coke or as soon as practicable thereafter.	Part 2, Table 1.db.1.ii.J	Yes
3.6	This permit does not authorize importing coke into the refinery and does not authorize the storage of coke in areas outside the coker silo and the coke barn.	Part 2, Table 1.db.1.ii.K	Yes
3.7	The differential pressure ranges for the scrubber and baghouses shall operate within the manufacturer's established ranges.	Part 2, Table 1.db.1.ii.L	Yes

3.8	The gravity chute and extendable load out spout for loading railcars shall extend to the railcar being loaded during railcar loading operations. The loading operation shall not generate any visible emissions at his transfer point.	Part 2, Table 1.db.1.ii.M	Yes
3.9	Railcar loading operations shall not be conducted unless its dust collector system is operating properly. Proper operation of the dust collector system shall be based on compliance with the manufacturer's recommended operating procedures and parameters.	Part 2, Table 1.db.1.ii.N	Yes
Deleted Title V Permit Conditions:	Part 2, Table 1.db.1.i.B Part 2, Table 1.db.1.ii.A, B, D, E, F, G Part 2, Table 1.db.1.iii.A through D Part 2, Table 1.db.1.v.A through H		

Table 2

Permit: APC-98/0522-OPERATION (A1)(NSPS) Cracked Naphtha Hydrotreater Heaters 25-H-401 and 25-H-402			
Condition No.	**Condition Description**	**Transferred to**	**Changes to related Compliance Methodology**
2.1.2	PM_{10} emissions shall not exceed the following: 1. For 25-H-401: 2.4 TPY on a rolling twelve month basis 2. For 25-H-402: 1.7 TPY on a rolling twelve month basis	Part 2, Table 1.ga.2.i.A	Yes
2.1.4	Sulfur dioxide (SO_2): A. For 25-H-401: 8.4 TPY on a rolling twelve month basis. B. For 25-H-402: 6.0 TPY on a rolling twelve month basis.	Part 2, Table 1.ga.3.i	Yes
2.1.5	Carbon Monoxide (CO): A. For 25-H-401: 10.9 TPY on a rolling twelve month basis. B. For 25-H-402: 7.7 TPY on a rolling twelve month basis.	Part 2, Table 1.ga.5.i	Yes
Deleted Title V Permit Conditions:	Part 2, Table 1.ga.1.i.C Part 2, Table 1.ga.1.iv.A through E Part 2, Table 1.ga.2.i.A.3		

	Part 2, Table 1.ga.5.i.c Part 2, Table 1.ga.6.i.B		

Table 3

Permit: APC-98/0523-OPERATION (A1)(NSPS) **Cracked Naphtha Hydrotreater Unit**			
Condition No.	**Condition Description**	**Transferred to**	**Changes to related Compliance Methodology**
2.1.1.3	Fugitive VOC emissions from the new equipment at the CNHT, SHU and DGA and new ancillary equipment and tie-ins shall not exceed 10.4 tons per year on a rolling quarterly basis.	Part 2, Table 1.ga.6.i.D	Yes
2.1.1.4	With the exception of leak definitions for pumps and valves specified above, the leak detection and repair requirements to control fugitive VOC emissions shall be in accordance with the requirements of 40 CFR 60, Subpart GGG for existing components in light liquid and gaseous service and in accordance with 40 CFR 63 Subpart CC for new components in light liquid and gaseous service. The leak detection and repair requirements to control fugitive emissions from the CNHT Unit shall be in accordance with the Consent Decree for both new and existing components in light liquid and gaseous service.	Part 2, Table 1.ga.6.i.D	Yes
3.1.1	There shall be no emissions of uncondensed VOCs from the condensers, hot wells, or accumulators of any vacuum producing system.	Part 2, Table 1.gb.1.ii.A	Yes
3.1.2	The Company shall provide for the following during process unit turnarounds: 1. Depressurization venting of the process unit or vessel to a vapor recovery system, flare or firebox. 2. No emission of VOC from a process unit or vessel until its internal pressure is 136kiloPascals (kPa) (19.7 psia) or less.	Part 2, Table 1.gb.1.ii.A	Yes

Deleted Title V Permit Conditions:	None.		

Table 4

Permit: APC-94/0710-OPERATION (A1)(NESHAP)(NOx RACT) WWTP Vapor Combustion Unit Fuel Switch Project			
Condition No.	**Condition Description**	**Transferred to**	**Changes to related Compliance Methodology**
2.1.4	SO_2 emissions shall not exceed 0.06 tons per year.	Part 2, Table 1.ac.2.i.B	Yes
2.1.1.1	VOC emissions shall not exceed 20 ppmv (dry) corrected to 3 percent O_2 and 0.5 tons in any rolling twelve month period from the VCU.	Part 2, Table 1.ac.4.i	Yes
2.1.5	Carbon Monoxide emissions shall not exceed 8.2 tons per year on a 12 month rolling basis.	Part 2, Table 1.ac.6.i	Yes
Obsolete Title V Permit Conditions Removed:	Part 2, Table 1.ac.3.i.A		

Table 5

Permit: APC-81/0829-OPERATION (A8)(PSD-NSR) Fluid Coker Unit, FCU COB, Wet Gas Scrubber and SNCR System			
Condition No.	**Condition Description**	**Transferred to**	**Changes to related Compliance Methodology**
3.7	During process unit turnarounds the Company shall provide for the following: 1. Depressurization venting of the process unit or vessel to a vapor recovery system, flare or firebox. 2. No emission of VOC from a process unit or vessel until its internal pressure is 136 kiloPascals (kPa) (19.7 psia) or less	Part 2, Table 1.da.1.i.I	Yes

3.6	There shall be no emissions of uncondensed VOCs from the condensers, hot wells or accumulators of any vacuum producing unit	Part 2, Table 1.da.1.i.J	Yes
2.1.3	PM from the FCU WGS: 1. TSP emissions shall not exceed 60.9 lb/hour and 266.8 TPY, and 2. PM_{10} emissions (including TSP and H_2SO_4) shall not exceed 128.4 lb/hour and 562.4 TPY	Part 2, Table 1.da.2a.i.C And Part 2, Table 1.da.2b.i.B	No
2.1.4	SO_2 emissions shall not exceed 25 ppmvd @ 0% O_2 on a rolling 365 day average, 50 ppmvd @ 0% O_2 on a rolling 7 day average, and 182.3 TPY	Part 2, Table 1.da.3.i.A	No
2.1.5	CO emissions from the FCU WGS shall not exceed 500 ppm dry @ 0% O_2 on an hourly average, 200 ppm dry @ 0% O_2 on a rolling 365 day average, and 694.4 TPY	Part 2, Table 1.da.5.i.A	No
2.1.1.1	VOC emissions from the FCU WGS shall not exceed 0.14 lb/mmDSCF of stack gas and 8.2 TPY	Part 2, Table 1.da.6.i.A	No
2.1.3.1	H_2SO_4 emissions from the FCU WGS shall not exceed 67.5 lb/hr and 295.7 TPY	Part 2, Table 1.da.7.i.B	No
2.1.7	Ammonia emissions from the FCU shall not exceed 2.3 lb/hour and 10.2 TPY	Part 2, Table 1.da.8.i	No
2.1.8	Pb emissions from the FCU shall not exceed 4.37 E-04 pounds per thousand pounds of coke burned and 0.12 TPY	Part 2, Table 1.da.9.i	No
2.1.9	Nickel (Ni) emissions shall not exceed 0.001 pounds per 1,000 pounds of coke burned and 0.27 TPY	Part 2, Table 1.da.10.i.A	No
3.9	HAP emissions from the FCU shall be controlled to meet the MACT I compliance requirements for miscellaneous process vents in accordance with 40 CFR 63.643(b).	Part 2, Table 1.da.10.i.B	No
Obsolete Title V Permit Conditions Removed:	None.		

Table 6

Permit: APC-82/0981-OPERATION (A9)(NSPS) Fluid Catalytic Cracking Unit, FCCU CO Boiler and WGS Sytem			
Condition No.	**Condition Description**	**Transferred to**	**Changes to related Compliance Methodology**
3.4	During process unit turnarounds the Company shall provide for the following: 1. Depressurization venting of the process unit or vessel to a vapor recovery system, flare or firebox. 2. No emission of VOC from a process unit or vessel until its internal pressure is 136 kiloPascals (kPa) (19.7 psia) or less	Part 2, Table 1.e.1.i.K	Yes
2.1.9	The Company shall evaluate the performance of the FCCU over a contiguous 30-month period to verify the improvements anticipated by the project (the equipment authorized to be constructed by APC-82/0981-CONSTRUCTION (A9)(NSPS) issued February 3, 2011). The Company shall, based on this evaluation, submit a proposal to incorporate revised and lower emission limits for PM and SO_2 emissions, to the Department for its approval and incorporation into an operating permit. The proposal shall be submitted to the Department within 90 days of the end of the evaluation period.	Part 2, Table 1.e.1.i.L	Yes
2.4	In the event that the FCCU COB is bypassed and/or shutdown, operation of the FCCU shall be in accordance with Attachment G of this permit.	Part 2, Table 1.e.1.i.M	No
2.5	The Emission Standards in Condition 3 - Table 1.e.4 through e.9 below, with the exception of e.7, shall not apply during periods when the FCCU COB is combusting refinery fuel gas only and during periods of planned shut downs and planned start ups of the FCCU for a period of time not to exceed 80 hours for each planned shut down and each planned start up event. The planned shut down period shall begin 8 hours prior to the time when there is no feed entering the FCCU reaction section. The planned start up	Part 2, Table 1.e.1.i.H	No

	period shall begin when dry-out of the FCCU is commenced. The Emission Standards in Condition 3 - Table 1.e.2 through e.9 shall apply to each planned start up event after the expiration of the 80 hour period following commencement of FCCU dry-out.		
2.1.5	SO_2 emissions from the FCCU WGS+ shall not exceed 25 ppmvd @ 0% O_2 on a rolling 365 day average, 50 ppmvd @ 0% O_2 on a rolling 7 day average, and 352 TPY.	Part 2, Table 1.e.3.i.A	No
2.1.6.1	CO emissions from the FCCU WGS+ shall not exceed 500 ppmv dry as a 1-hour average, and 3,085 TPY.	Part 2, Table 1.e.5.i.A	No
3.3	There shall be no emissions of uncondensed VOCs from the condensers, hot wells or accumulators of any vacuum producing system.	Part 2, Table 1.e.6.i.C	Yes
Obsolete Title V Permit Conditions Removed:	Part 2, Table 1.e.10.iii.D and E Part 2, Table 1.e.2a.i.A		

Table 7

Permit: APC-97/0503-OPERATION (Amendment 8)(NSPS) CCU Modification Project			
Condition No.	**Condition Description**	**Transferred to**	**Changes to related Compliance Methodology**
3.1	Only NG may be fired in the combustion chambers of the CCUs. Only NG or desulfurized RFG with a hydrogen sulfide content less than 0.1 grain/dscf on a 3-hour rolling average may be fired in the DBs.	Part 3, Table 1.d.1.ii.H	Yes
3.2	The CCUs shall not be operated unless the LNBs are operating properly.	Part 3, Table 1.d.1.ii.I	Yes
3.3	During startups and shutdowns of the combustion turbines and/or duct burners shall apply: 1. CO emissions concentration limitations specified in Table 1.d.5 shall not apply. The Company shall follow good air	Part 3, Table 1.d.1.ii.J	No

	pollution control practices to minimize emissions during these peak periods. 2. NOx emission rates from the CCUs shall not exceed 390 ppmv(dry) at 15% O_2. 3. Such periods shall not exceed 2 hours in duration.		
2.1.4	PM_{10} emissions including H_2SO_4 shall not exceed the following limits: 1. 0.0074 lb/mmBtu when firing natural gas in CCUs. 2. 0.0099 lb/mmBtu when firing natural gas in the CCUs and refinery fuel gas in the duct burners. 5. 67 tons per year	Part 3, Table 1.d.2.i.B 1, 2 and 5	No
2.1.5	TSP emissions shall not exceed the following limits: 1. 0.0115 lb/mmBtu when firing natural gas in CCUs. 2. 0.0112 lb/mmBtu when firing natural gas in the CCUs and refinery fuel gas in the duct burners. 5. 47.8 tons per year.	Part 3, Table 1.d.2.i.D 1, 2 and 5	No
2.1.3	CO emissions on an hourly basis shall not exceed the following limits: 1. 0.0202 lb/mmBtu when firing natural gas in CCUs. 2. 0.0261 lb/mmBtu when firing NG in the CCUs and refinery fuel gas in the duct burners. 5. 110.9 tons per year.	Part 3, Table 1.d.5.i.B 1, 2 and 5	No
2.1.6	VOC as measured by the average of the three stack test runs pursuant to the stack tests: 1. 0.0021 lb/mmBtu when firing natural gas in CCUs. 2. 0.0046 lb/mmBtu when firing natural gas in the CCUs and refinery fuel gas in the duct burners. 5. 19.8 tons per year	Part 3, Table 1.d.6.i.B 1, 2 and 5	No
2.1.7	H_2SO_4 as measured by the average of the three stack test runs shall not exceed 3.1 tons per year.	Part 3, Table 1.d.10.i	Yes
2.1.8	Lead emissions shall not exceed 0.004 tons per year.	Part 3, Table 1.d.11.i	Yes
2.1.2.1	SO_2 emissions shall not exceed 36.5 tons per year.	Part 3, Table 1.d.12.i	Yes

Obsolete Title V Permit Conditions Removed:	Part 3, Table 1.d.1.ii.A, B, C, F, G Part 3, Table 1.d.2.i.B.3 and 4 Part 3, Table 1.d.2.i.D.3 and 4 Part 3, Table 1.d.4.i.C.3 and 4 Part 3, Table 1.d.4.ii.A and B Part 3, Table 1.d.5.ii.B.3 and 4		

Table 8

Permit: APC-80/0868-OPERATION (Amendment 3)(MACT)(VOC RACT)(NSPS) – Tanks 166, 205 & 261 **Permit: APC-80/0869-OPERATION (Amendment 6)(MACT)(VOC RACT)(NSPS)** – Tank 47			
Condition No.	**Condition Description**	**Transferred to**	**Changes to related Compliance Methodology**
3.1.13	Emergency roof drains shall have slotted membrane fabric covers or equivalent covers that cover at least 90% of the area of the opening.	Part 1, Table 1.fb.1.ii.G	No
2.1.1	For Tanks 47, 166, 205, and 261: VOC emissions from the tanks shall not exceed 4.9 tons per 12 month rolling average.	Part 1, Table 1.fb.1.iii.A And cross-referenced in Part 1, Table 1.ff.1.v.B	Yes
4.4	For Tanks 166, 205, and 261: The requirements of **Permit: AQM-003/00016 – Part 2** Condition 3 – Table 1.oa shall apply to the new fugitive VOC sources associated with these tanks.	Part 1, Table 1.fb.1.iii.B Part 1, Table 1.ff.1.v.C	No
Obsolete Title V Permit Conditions Removed:	Part 1, Table 1.fb.1.iii.A		

Table 9

Permit: APC-81/0828-OPERATION (Amendment 2)(PSD-NSR) Crude Unit			
Condition No.	**Condition Description**	**Transferred to**	**Changes to related Compliance Methodology**
3.1.2	There shall be no emissions of uncondensed VOCs from the condensers, hot wells or accumulators of any vacuum producing system.	Part 2, Table 1.c.1.i.E	Yes
3.1.3	The Company shall provide for the following during process unit turnarounds: 1. Depressurization venting of the process unit or vessel to a vapor recover ysystem, flare or firebox. 2. No emission of VOC from a process unit or vessel until its internal pressure is 136 kPa (19.7 psia) or less.	Part 2, Table 1.c.1.i.E	Yes
Obsolete Title V Permit Conditions Removed:	No emission limits or standards were removed.		

REQUESTED CHANGES IN THE RENEWAL PERMIT

The Refinery has requested the following three changes to the permit language:

Table 10

Title V Permit Condition	Current Language	Proposed Language	Rationale	DAQ Determination and Comments
Part 1, Cond. 3 – Table 1.ba.1.vi.A	A Notification of Compliance Status (NCS) in accordance with 40 CFR Part 63.152 shall be submitted semi-annually, no later than 60 days after the end of each 6 month period. The 6	A Notification of Compliance Status (NCS) in accordance with 40 CFR Part 63.152 shall be submitted semi-annually, no later than 60 days after the end of each 6 month period. The 6	Believed to be a typographic error. The proposed change is consistent with the historic submission schedule for this	DAQ concurs and has made this change in the draft permit.

	month periods for this facility shall end on *June 30* and *December 31*, respectively each year.	month periods for this facility shall end on *May 19* and *November 19*, respectively each year.	report. The underlying Regulation 1102 permit (APC-81/0832) contains the May and November reporting periods.	
Part 1, Cond. 3 – Table 1.bb.1.vi.A	The startup, shutdown, and malfunction report shall be delivered or postmarked by the *January 22 and July 22* of each year for the periods of *May 1 - November 30* and *December 1 - June 31* respectively.	The startup, shutdown, and malfunction report shall be delivered or postmarked by the *January 30 and July 30* of each year for the periods of *July 1 - December 31* and *January 1 - June 30* respectively.	Believed to be a typographic error. The reporting periods currently contained in the permit overlap and contain a nonexistent day (June 31). The proposed change is consistent with the specified schedule set forth in 40 CFR 63.10(d)(5)(i).	DAQ concurs and has made this change in the draft permit.
Part 2, Cond. 3 – Table 1.m.5.ii.B	The minimum *hourly* average pH of the scrubbing liquid exiting the scrubber shall be 6.56.	The minimum *daily* average pH of the scrubbing liquid exiting the scrubber shall be 6.56.	Believed to be a typographic error. Condition 3 -Table 1.m.iv.B.2 (Monitoring and Testing provision) requires the daily average pH to be maintained above the operating limit established during the performance test. The minimum liquid-to-gas ratio is also a daily average. Also, the Operating, Maintenance and Monitoring plan submitted by Premcor to EPA in Sept 2005 also proposes a daily average pH as a Control Device operating Limit.	DAQ concurs and has made this change in the draft permit.

ADDITIONAL CHANGES TO THE TITLE V PERMIT

1. The amine acid gas removal system was taken offline and is no longer operational. Relevant conditions in Part 3 Condition 3 – Table 1.c have been removed.
2. The Facility Wide conditions in Table 3 Condition 3 table 1.e were duplicative to those in Part 2 Condition 3 – table 1.ob. They have been removed from Part 3 and a cross reference notice has been placed here.
3. The two Gasifiers (Emission Unit 82) have been taken offline and are no longer operational. Relevant conditions in Part 3 Condition 3 – Table 1.f have been removed.
4. DCRC's Title V permit has a Plantwide Applicability Limit for NOx as a federally enforceable NOx Cap that has been incorporated in Sections jb and jc of Part 1of the permit. Because EPA and the State of Delaware were still in the process of developing the appropriate conditions to include in PAL permits at the time when the NOx Cap provisions were developed for DCRC's Title V permit in April 2011, the current version of the Title V permit does not include these new revised conditions. DAQ is now incorporating the revised applicable conditions as developed by EPA and the State of Delaware in this permit renewal. Therefore, DAQ has incorporated the following conditions in DCRC's TV permit:
5. The NOx Cap shall remain in effect until the date of expiration of this permit.
    - 5.1 Compliance with the NOx Cap limitation in this permit shall constitute compliance with Sections 2 and 3 of 7 DE Admin. Code 1125 with respect to these pollutants;
    - 5.2 The owner and/or operator may request to continue the NOx Cap by submitting a request for renewal at least six months prior to, but not earlier than eighteen months prior to, the date of permit expiration. If the owner and/or operator submits a complete application to renew the NOx Cap within this time period (between DATE and DATE), then the NOx Cap shall continue to be effective until the revised permit with the renewed NOx Cap is issued.
        - 5.2.1 The extension of the permit terms under 5.2 cannot remain in effect beyond a date ten years from issuance of the NOx Cap. If the NOx Cap has not been reevaluated and reissued by that date it shall expire.
    - 5.3 If the potential to emit NOx from all stationary sources at the facility subject to the NOx Cap is less than the limitations set in the NOx Cap, the Department shall adjust the limitations in the NOx Cap, as applicable, to a level no greater than the potential to emit.
    - 5.4 The Department shall not approve a renewed NOx Cap limitation at a limit higher than that given in Condition jb.1.i unless the owner and/or operator has complied with the requirements given in Condition 8 of this section of this permit.
    - 5.5 If the Department has not already lowered the NOx Cap limitations as necessary based upon the requirements of Condition 1.6 of this section of this permit, the NOx Cap limitations shall be lowered at the time of permit renewal.
    - 5.6 If the NOx Cap is not renewed in accordance with the requirements of Condition 5.2, the NOx Cap shall expire at the end of the NOx Cap effective period, and the requirements below shall apply:
    - 5.6.1 Each emissions unit (or each group of emissions units) that existed under the NOx Cap shall comply with an allowable emission limitation under a revised permit established according to the procedures in Conditions 5.6.1.1 and 5.6.1.2:
        - 5.6.1.1 Within the time frame specified for NOx Cap renewals in Condition 6.2 of this section of the permit, the major stationary source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as decided by the Administrator) by distributing the NOx

Cap allowable emissions for the major stationary source among each of the emissions units that existed under the NOx Cap. If the NOx Cap had not yet been adjusted for an applicable requirement that became effective during the NOx Cap effective period, such distribution shall be made as if the NOx Cap had been adjusted.

5.6.1.2 The Department shall decide whether and how the NOx Cap allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the Department determines is appropriate.

5.6.2 Each emissions unit(s) shall comply with the allowable emission limitation on a 12-month rolling basis. The Department may approve the use of monitoring systems (source testing, emission factors, etc.) other than CEMS, CERMS, PEMS, or CPMS to demonstrate compliance with the allowable emission limitation.

5.6.3 Until the Department issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the NOx Cap emission limitation.

5.6.4 Any physical change or change in the method of operation at the major stationary source will be subject to major NSR requirements if such change meets the definition of major modification in 40 CFR 52.21 (b)(2).

5.6.5 The major stationary source owner or operator shall continue to comply with any State or Federal applicable requirements (BACT, RACT, NSPS, etc.) that may have applied either during the NOx Cap effective period or prior to the NOx Cap effective period except for those emission limitations that had been established pursuant to paragraph 40 CFR 52.21 (r)(4), but were eliminated by the NOx Cap in accordance with the provisions in 40 CFR 52.21 (aa)(1)(ii)(c).
[Reference 7 DE Admin. Code 1130 Section 6.1.2.1 dated 12/11/00 and Section 7.3.1 dated 12/11/00 and 40 CFR 52.21(aa)(7) dated 6/3/2010]

6. The NOx Cap provisions of this permit may be reopened to: [Reference 7 DE Admin. Code 1130 Section 7.6 dated 12/11/00]

6.1 Reduce the NOx Cap to create emission reductions for offset purposes;

6.2 Reduce the NOx Cap to reflect newly applicable Federal and State requirements with compliance dates after the PAL effective date; or

6.3 Reduce the NOx Cap for any pollutant consistent with any other requirement that may be imposed under the State Implementation Plan (SIP).

6.4 Any downward adjustment that is required under Condition 3.2.2 or 3.2.3 will be based upon the contribution of the affected source(s) to actual emissions at the time the rule goes into effect.

7. The owner and/or operator shall not construct new stationary sources, modify existing stationary sources, or operate existing stationary sources such that the NOx Cap is exceeded. The owner and/or operator shall comply with 7 DE Admin. Code 1125, "Preconstruction Review", for any proposed activity that necessitates an increase in the NOx Cap in accordance with the following provisions:
[Reference 7 DE Admin. Code 1102, Section 12.4 dated 6/11/2006 and 7 DE Admin. Code 1130 Section 7.4 dated 12/11/2000]

7.1 The owner and/or operator shall demonstrate that significant and major emission units at the facility meet Best Available Control Technology

(BACT), equivalent BACT, or an equivalent level of control for each pollutant that an increase is being requested for:

7.1.1 The demonstrations shall be in the form of a BACT analysis unless the emissions unit is currently subject to a current (i.e. within the past ten years) BACT or Lowest Achievable Control Technology (LAER) requirement;

7.1.2 The owner and/or operator shall demonstrate to the Department's satisfaction that is not economically feasible to reduce emissions of the NOx Cap by further controlling emission units at the facility.

7.2 A new emissions unit that necessitates an increase in the NOx Cap shall be treated as a new major source and shall comply with 7 DE Admin. Code 1125.

7.3 The air quality impacts analysis as shown in 40 CFR 51.166(m) (July 1, 2005 edition) shall demonstrate that the increase will not cause or contribute to a National Ambient Air Quality Standard (NAAQS) or Prevention of Significant Deterioration (PSD) increment exceedance.

7.4 Revisions to the NOx Cap shall be incorporated into the facility's Title V Permit in accordance with the provisions of 7 DE Admin. Code 1102 Section 12.4 and 7 DE Admin. Code 1130 Section 7.4.

7.5 The increased NOx Cap level shall be effective upon the date of incorporation into the facility's Title V Permit.

8. The provisions of 7 DE Admin. Code 1125 Sections 1 through 3 shall not apply to emissions units that that are proposed modifications with increases in associated NOX emissions or to proposed new emission units so long as the Plantwide Applicability Limits in Condition 2.1 are not exceeded. Except for the pre-approved changes described in Condition 3.5 of this permit, 7 DE Admin. Code 1125 Section 4, "Minor New Source Review", shall continue to apply to emission units that are proposed modifications with increases in associated NOX emissions or to proposed new emission units. A complete application meeting all of the requirements of 7 DE Admin. Code 1125 Section 4 and 7 DE Admin. Code 1102 shall be submitted with sufficient information for public notice. The owner and/or operator shall specifically follow the requirements of 7 DE Admin. Code 1102 Section 12.4 and 7 DE Admin. Code 1125 Section 4 in order for the terms and conditions of the construction permit to be transferred into the 7 DE Admin. Code 1130 permit via the administrative amendment process specified in 7 DE Admin. Code 1130 Section 7.4. [Reference 7 DE Admin. Code 1125 Section 4.0 dated 8/11/05, 7 DE Admin. Code 1102 Section 11.0 dated 6/11/06 and Section 12.4 dated 6/11/06, and 7 DE Admin. Code 1130 Section 7.4 dated 12/11/00]

9. The following Pre-Approved Changes shall be treated as alternate operating scenarios. The owner and/or operator is approved to make the changes listed under Conditions 8.1 and 8.2 of this section so long as the NOx Cap is not exceeded and the activity will not result in a newly constructed or reconstructed major source of hazardous air pollutants as defined in and subject to 40 CFR Part 63.2 and Part 63.5(b)(3), National Emission Standards for Hazardous Air Pollutants. The owner and/or operator shall comply with all certification, monitoring, testing, record keeping, and reporting requirements listed in this permit for the following pre-approved changes. Any change that is subject to a new applicable requirement that is not listed in this permit shall prior to implementation comply with the permit revision procedures of this permit so long as to incorporate the new requirement into the permit.

9.1 Conventional Pre-Approved Changes [Reference 7 DE Admin. Code 1130 Section 6.8 dated 12/11/00]
- 9.1.1 The emission unit is replaced in kind or replaced with a unit with inherently lower emissions;
- 9.1.2 Operational changes which will not increase any short term NOX emission limit established in Permit: AQM-003/00016 or any renewals or revisions thereof for NOX; and
- 9.1.3 Any of the exemptions listed under 7 DE Admin. Code 1102 Appendix A.

9.2 PAL Pre-Approved Changes
- 9.2.1 In-kind replacement of an emissions unit or replacement with an inherently lower emitting unit.

9.3 Any activity that will result in a newly constructed or reconstructed major source of hazardous air pollutants (HAPs) as defined in and subject to 40 CFR Part 63.2 and 63.5(b)(3), National Emission Standards for Hazardous Air Pollutants, shall submit a registration in accordance with Section 9 of 7 DE Admin. Code 1102 or a permit application in accordance with Section 11 of 7 DE Admin. Code 1102 and receive approval from the Department prior to initiating the change.) [Reference 7 DE Admin. Code 1102 Section 9.0 dated 6/1/97 and Section 11.0 dated 6/11/06]

10. Any activity initiated under Condition 9 that involves the installation of new emission units as part of the source defined in Condition jb.1.i shall submit:

10.1 A registration in accordance with Section 9 of 7 DE Admin. Code 1102; or

10.2 A permit application in accordance with Section 11 of 7 DE Admin. Code 1102 and the following provisions:
- 10.2.1 The new emission units, as applicable, shall comply with 7 DE Admin. Code 1125 Section 4;
- 10.2.2 Any air pollution control technology requirements that result from the application of 7 DE Admin. Code 1125 Section 4 shall be reflected in the operating permit;
- 10.2.3 No additional unit specific NOx emission rate requirements will be added to the NOx Cap permit so long as NOx Cap limits are not exceeded ; and
- 10.2.4 Forty-five days following the public notice, unless the Department objects or issues supplemental conditions, the project with be automatically approved. Should a public hearing be requested, the automatic approval process will cease.

[Reference 7 DE Admin. Code 1102 Section 9.0 dated 6/1/97 and Section 11.0 dated 6/1/06 and 7 DE Admin. Code 1125 Section 4.0 dated 8/11/05]

11. The Department shall determine the need for unit specific emission factors for any new NOX emitting emission unit constructed after issuance of this permit or for any modification to an existing NOX emission unit that will be covered under the NOx Cap. Unit specific emission factor requirements for any new NOX emitting unit or for any modification to an existing NOX emission unit will be covered in the new unit's construction permit and will be incorporated into Permit: AQM-003/00016 or any renewal or revision thereof.

12. Additionally, Table 11 below provides a compendium of NOx emitting sources within

the refinery and provides a justification for the monitoring strategy incorporated in the permit. As seen in table 11, there are 52 NOx emitting point sources in the refinery. Collectively these sources represent a maximum heat input of 8531 mmBtu/hour[1]. On a heat input basis, NOx emissions resulting from emissions units totaling 7097 mmBtu/hour are monitored by CEMS, i.e., 83.2 %. Annual stack tests are required for units totaling 727 mmBtu/hour and NOx emissions from the remaining units are based on fuel usage, fuel quality and representative emissions factors.

[1] The aggregate heat input figure does not include the 2 refinery flares, the thermal oxidizers at the marine piers and the FCU back up incinerator which does not normally operate.

Unit	Heat Input mmBtu/Hr	Fuel Type	CEMS	Annual Stack Test
WWTP Vapor Combustion Unit 10-3	23	NG	N	N
Marine Vapor Recovery Oxidizer # 1 15-1	N/A	NG	N	N
Marine Vapor Recovery Oxidizer # 2 15-2	N/A	NG	N	N
Crude Unit Atmospheric Heater 21-H-701	530	NG/RFG	Y	N
Crude Unit Vacuum Heater 21-H-2	240	NG/RFG	Y	N
Fluid Coking Unit (FCU) Start Up Heater 22-H-1	107	NG/RFG	Y	N
FCU Selas Superheater 22-H-2	18	NG/RFG	N	N
FCU COB 22-H-3	675	NG/RFG/CO	Y	N
FCU Back up Incinerator 22-H-4	976	NG/RFG/CO	N	N
Fluid Catalytic Cracking Unit (FCCU) Start Up Heater 23-H-1A	82	NG/RFG	Y	N
FCCU Start Up Heater 23-H-1B	82	NG/RFG	Y	N
FCCU COB 23-H-3	680	NG/RFG/CO	Y	N
Cracked Naphtha Hydrotreater Feed Heater 25-H-401	80	NG/RFG	N	Y
Cracked Naphtha Hydrotreater Reboiler 25-H-402	57	NG/RFG	N	Y
Cracked Naphtha Hydrotreater SCOT 1 28-S-201	44	NG/RFG	N	Y
Cracked Naphtha Hydrotreater SCOT 2 28-S-202	45	NG/RFG	N	Y
Hydrodesulfurizer Train 1 Feed Heater 29-H-101	66	NG/RFG	N	N
Hydrodesulfurizer Train 2 Feed Heater 29-H-2	32	NG/RFG	N	N
Hydrodesulfurizer Train 3 Feed Heater 29-H-3	21	NG/RFG	N	N
Hydrodesulfurizer Train 4 Feed Heater 29-H-4	37	NG/RFG	N	N
Hydrodesulfurizer Train 5 Feed Heater 29-H-5	44	NG/RFG	N	N
Hydrodesulfurizer Train 5 Fractionator Heater 29-H-6	50	NG/RFG	N	N
Hydrodesulfurizer Train 4 Fractionator Heater 29-H-7	34	NG/RFG	N	N
Hydrodesulfurizer Train 1 Fractionator Heater 29-H-8	50	NG/RFG	N	N
Hydrodesulfurizer Train 3 Fractionator Heater 29-H-9	28	NG/RFG	N	N
Tetra feed heater 32-H-101	101	NG/RFG	N	Y
Tetra Unit Bottoms Heater 32-H-102	43	NG/RFG	N	N
Tetra Unit Heater 32-H-103	29	NG/RFG	N	N
Selective Hydrogenation Unit Start Up Heater 33-H-1	8	NG/RFG	N	N
SHU Reboiler Heater 33-H-2	38	NG/RFG	N	N
Olefins Plant Reboiler Heater 134-H-101	35	NG/RFG	N	N
Hydrocracker Feed Heater 36-H-1	45	NG/RFG	N	N

Hydrocracker Vacuum Column Reboiler Heater 36-H-2	15	NG/RFG	N	N
Hydrocracker Fractionator Heater 36-H-3	34	NG/RFG	N	N
Hydrogen Plant Reformer Heater 37-H-1 A/B	337	NG/RFG	Y	N
Utilities North Flare 45-1	N/A	NG/RFG	N	N
Utilities South Flare 45-2	N/A	NG/RFG	N	N
CCR Reformer Heater 42-H-1,2,3	353	NG/RFG	Y	N
Boiler 1 80-1	618	NG/RFG	Y	N
Boiler 2 80-2	716	NG/RFG	Y	N
Boiler 3 80-3	618	NG/RFG	Y	N
Boiler 4 80-4	737	NG/RFG	Y	N
CCU 1 84-1	780	NG	Y	N
CCU 2 84-2	780	NG	Y	N
CCU 1 Duct Burner	190	NG/RFG	Y	N
CCU 2 Duct Burner	190	NG/RFG	Y	N
Package Boiler 1 45-B-150	100	NG/RFG	N	Y
Package Boiler 1 45-B-250	100	NG/RFG	N	Y
Package Boiler 1 45-B-350	100	NG/RFG	N	Y
Package Boiler 1 45-B-450	100	NG/RFG	N	Y

FACILITY WIDE REQUIREMENTS

1990 CAAA, Section 112(r)
The facility is subject to and has registered in compliance with the State of Delaware.

1990 CAAA, Title VI
The facility has air conditioners and refrigeration equipment that use CFCs, HCFCs, or other ozone depleting substances. The equipment contains a refrigerant charge greater than 50 pounds. Facility personnel do maintain, service, repair or dispose of any motor vehicle air conditioners or appliances, as defined in 40 CFR Part 82.152. The refinery's application states 40 CFR Part 82 subparts B and F are applicable to the facility but not applicable to any unit covered by the Title V part 1 permit.

Compliance Schedule
The facility is not under a compliance schedule.

Permit Shield
The facility has not requested a Permit Shield.

Compliance Assurance Monitoring (CAM) Rule

DCRC's application included a CAM plan submitted on Form AQM-1001EE for the Marine Vapor Recover (MVR) System. The MVR's CAM applicability determinations show it meets the following criteria: (1) it is located at a major source that requires a Title V permit (2) its subject to an emission limitation for a regulated air pollutant that is not exempt (3) it uses an add on control to achieve compliance with the emission limitation (4) it has pre-control device emissions that are greater than the major source threshold and (5) it is not an exempt backup utility power emissions unit.

Barge loading operations at the loading piers have a potential to emit VOC emissions greater than the major source threshold of 25 TPY. The MVR System uses an induced flow vapor recovery system routed to enclosed flares to reduce emissions by 98% by weight or to 1,000 ppmv.

The refinery's CAM plan states it will use the loading rate and the flame presence as indicators of its monitoring approach.

Table 12

	Indicator No. 1	Indicator No. 2
Monitoring Approach and Permit Citation	DCRC shall continuously monitor the hourly loading rate of all gasoline products at each pier during loading operations	A sensing device shall be calibrated, maintained and operated to indicate the continuous presence of a flame at the pilot light during the entire loading cycle.
	Part 2, Table 1.b.5.iv.A	Part 2, Table 1.b.5.iv.B
Indicator Range and Permit Citation	Barge loading of gasoline products shall not exceed the following rates: 1. 35,000 barrels hour when loading	A flame must be present during the entire loading cycle.

	simultaneously at two piers; and 2. 25,000 barrels per hour at one pier	
	Part 2, Table 1.b.5.ii.A	Part 2, Table 1.b.5.ii.G

Stack testing, required every 5 years per Part 2 Condition 3 – Table 1.b.5.iv.C, is performed to ensure compliance. The last stack test was performed in December 2011 and showed the MVR system to be in compliance with applicable requirements.

RECOMMENDATION

It is recommended the draft operating permit be issued to the Company and the EPA, and advertised in the News Journal for the 30-day public review period and the affected states of Maryland, New Jersey and Pennsylvania.

PEF:CRR:slb
F:\EngAndCompliance\crr13007

pc: Dover Title V File
Paul E. Foster, P.E.